How much capacity deferral value can targeted solar deployment create in Pennsylvania?

Jeremy F Keen[1] and Jay Apt[1,2]

[1] Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, PA 15213, USA
[2] Tepper School of Business, Carnegie Mellon University, Pittsburgh, PA 15213, USA

E-mail: jkeen@andrew.cmu.edu

Keywords: value of solar, distribution network, energy storage, capacity deferral

Abstract

We assess the ability of distributed solar to defer distribution capacity projects in a typical low load growth utility in the Northeast USA, PECO. We find that targeted placement can increase the deferral value of solar up to fourfold, but that deferrable projects are rare. In our baseline scenario, we find a 5% solar energy penetration with Net Energy Metering rolled out from 2020-2030 would increase rates by 0.9% over a 20-year horizon and generate just $1MM in net present deferral value. This estimate assumes untargeted placement of solar, a low effective capacity (i.e. the reduction in peak load relative to solar's nominal capacity), a 1% growth rate, and 1% of PECO's distribution yearly capex budget that is deferrable. A higher effective capacity (e.g. from coupling energy storage with solar) and targeted placement could generate a net $8MM of value over the same horizon but the rate increase is mostly unaffected (dropping to 0.8%). We recommend the use of targeted solar placement in utility planning processes. Compared to untargeted placement, targeted placement can increase the total deferral value fourfold, but the effect on rates is small because few capacity deferral opportunities exist.

1. Introduction

More than 30 states have grid modernization plans (Trabish, 2017). New York's Reforming Energy Vision (REV) and California's Distribution Resources Plan (DRP) are both frameworks that incorporate solar and other DER into their utilities' planning processes. Both the REV and DRP rely on the Electric Power Research Institute's (EPRI) "Integrated Grid Framework" (EPRI, 2015). Key features of the "Integrated Grid" are hosting capacity maps and locational value maps that, respectively, show how much DER can be placed on the network without violating system constraints and show developers where DER may have value.

The capacity deferral value of solar (VOS) is one benefit frequently cited in grid modernization plans (New York DPS, 2015; CPUC, 2016). Capacity deferral value is the value that solar creates by reducing overloaded equipment and deferring capital investments to later years. The present worth method for estimating the value of capacity deferral is used by academics and consultants (Woo, et al. 1994; Willis, 2000). In this method, solar or other DER causes a load reduction on an overloaded feeder and capital investments in that feeder are deferred to later years. Net Present Value (NPV) calculations are used to estimate the deferral value. That value is divided by the total generated solar energy to find the value of solar ($/kWh-solar). The result is sensitive to the cost of deferrable capacity projects, load growth on the feeder, and how solar's nominal capacity is credited with reducing peak loads.

Although several studies have estimated the capacity deferral VOS, we are not aware of any published work that evaluates how utility policies regarding solar placement affects the VOS and the total deferral value created. It is important to consider solar placement because most statewide solar penetration targets are often modest and the solar is deployed over many years. The result is small incremental solar additions to the locations that could benefit from capacity deferral, which may not be enough solar to defer investments by useful amounts of time.

Throughout the literature review and our analysis, we use three planning classifications.

1. *No targeting (random) placement:* Rooftop solar is placed without regard to locations with overloading and without overloading, and all rooftop solar owners are compensated for the value created by solar.
2. *Targeted Compensation:* Rooftop solar is placed randomly without regard to location, but rooftop solar owners are compensated only if they are in overloaded networks.
3. *Targeted Placement:* A fraction of rooftop solar is placed purposely in overloaded locations. The amount of rooftop solar placed in overloaded locations is limited by the hosting capacity.

We define hosting capacity as the amount of solar that can be added without causing thermal overloading or voltages in excess of the ANSI C84.1 (range A) limit on the primary and secondary networks. The hosting capacity is expressed as this maximum nameplate solar AC capacity relative to the feeder's peak load.

In the *No Targeting* scenario, no effort is made to place solar where it is needed. Deferral value opportunities are missed, which decreases the total deferral value created and the VOS. The *Targeted Compensation* VOS is sometimes estimated in studies (Cohen et al., 2016; NYSERDA, 2015). It does not create any more total deferral value than the no targeting scenario but results in a higher VOS because it distributes capacity deferral value among a smaller number of solar owners. In contrast, *Targeted Placement* puts more solar in locations where it is needed, ensuring that deferral opportunities are not missed and creates longer deferral times. The result is a higher VOS and a higher total deferral value.

Our purpose here is to determine how much targeted placement of solar on overloaded networks can increase the total deferral value and reduce the rate increase observed under a 5% solar energy penetration with untargeted solar. We find that targeted placement can increase the deferral value of solar up to fourfold, but the effect on rates is small because few capacity deferral opportunities exist. In the remainder of this paper, we first discuss the assumptions used in other studies, which examine capacity deferral value without targeted solar placement. Next, we describe the model we use to estimate how both targeted and untargeted solar placement affects capacity deferral and how capacity deferral affects customer rates. We find that targeted solar placement should be included in utility planning processes but due to the low number of capacity deferral opportunities in PECO's service territory, large administrative efforts to manage deferral projects, such as markets, are not warranted. We conclude with policy and research recommendations.

2. Comparison with Previous Research

Several studies have estimated the distribution deferral VOS assuming random solar placement. In a report for EPRI O'Connell et al. (2017) find "PV is a poor alternative as firm available capacity to grid reinforcements" mainly because of both winter and evening peaking feeders in the Murcia region of Spain where the study took place. In New York, Energy and Environmental Economics (E3) estimates the distribution deferral value of solar at ~0.5₵/kWh without targeting and ~2.5₵/kWh with targeted compensation (NYSERDA, 2015). The most comprehensive study that we are aware of is by Cohen et al. (2016).

Cohen et al. (2016) use the Pacific Northwest National Lab feeder taxonomy, and detailed PG&E data on capital expenditures and feeder growth rates to estimate how solar rollouts with different speeds affect the distribution deferral value of solar. They estimate a value of solar in the PG&E service territory from 0.05-0.2₵/kWh without targeting and 0.25-1₵/kWh under targeted compensation. The ranges are based on varying rollout scenarios over 10 years. Faster solar rollouts are able to create more total deferral value by deferring capacity projects with earlier start dates. However, faster solar rollouts generate more solar energy years before some projects need to be deferred, resulting in a lower value of solar. Varying rollout speeds cannot be easily compared with targeted placement of solar, which allows for more solar on overloaded networks at the time it is needed.

We are not aware of any study that estimates the deferral value of solar using targeted solar placement. Additionally, we are not aware of any study that performs a sensitivity analysis on some of the key parameters that affect the distribution deferral value of solar: the cost of replacing equipment, load growth, and the how solar's nominal capacity is credited with reducing peak loads.

The marginal cost of service (MCOS) is the cost of replacing or augmenting overloaded equipment. Cohen et al. (2016) use a dataset that includes feeder level capacity expenditures and growth rates but do not disclose these data. E3 has published MCOS values for each of the New York utilities ranging from $250/kW to $1000/kW and averaging $750/kW (NYSERDA, 2015). In E3's avoided cost calculator (E3, 2018), the MCOS is approximately $600/kW[1]. As discussed below, we also estimate PECO's MCOS to be $600/kW, based on four growth related projects planned for the next five years. These MCOS values are representative of capacity investments on distribution network primary systems. MCOS estimates for distribution secondary networks can be found in E3's avoided cost calculator, ranging from $10-40/kW (E3, 2018).

The capacity deferral value of solar is sensitive to feeder load growth. If the load growth is low, the deferral will be longer. We are not aware of any value of solar studies that provide feeder load growth assumptions, but a Brattle study on the Economic potential of energy storage in Nevada by Hledik et al. (2018) assumes 2% load growth explaining that "locations requiring upgrades may be experiencing higher than average load growth."

Several methods are used for estimating how solar's nominal capacity is credited with reducing peak loads. E3 uses the Peak Capacity Allocation Factor (PCAF) to assign a capacity credit to solar (Horii et al., 2016). The PCAF method estimates the capacity credit based on solar's contribution to peak load reduction during daily peak load events within one standard deviation of the largest yearly peak. An advantage of the PCAF method is that it creates a temporal component to the distribution value of solar. A disadvantage is that the PCAF does not immediately depict the declining capacity value of solar with

[1] This is the average avoided capacity cost of all zones in PG&E's service territory. E3 provides avoided capacity costs in $/kW-year, but we use $/kW in this chapter. We converted to $/kW assuming a 30 year lifetime and a 7% discount rate.

increasing penetrations (Mills and Wiser, 2012). Cohen et al. (2016) instead base the capacity credit only on peak loading days and do capture the declining value of solar with increasing penetration. They estimate roughly a 50% reduction in the capacity credit of solar at a 50% penetration. Our method for estimating the capacity credit is most similar to Cohen et al. (2016), but is based on 19 years of loading data that is used to find a "Distribution Effective Load Carrying Capability" (D-ELCC). Details are in the method section below and described by Keen (2019).

3. Method

3.1 Utility Rate Impact Model

We have developed a utility rate impact model that serves as the foundation of our capacity deferral model and generates three yearly metrics: the all-in-rate, reduced earnings, and value of solar. The utility rate impact and capacity deferral modeling are done with Analytica®. It was adapted from a spreadsheet model developed by E3 for the National Action Plan for Energy Efficiency (NAPEE, 2007) and later work by Satchwell et al. (2014), which focused on solar's effect on a prototypical deregulated northeast utility and a southwest vertically integrated utility.

The utility rate impact model estimates how the combination of avoided costs associated with solar and lost revenue associated with NEM ultimately affect rates. First, the model forecasts PECO's revenue requirement (revenue needed to pay for the cost of service, utility debt, and equity), including pass-through costs and non-pass-through costs. The model begins with PECO's revenue requirement in the year 2016 and forecasts each revenue requirement component based on the relevant escalation factors (see Table A1). The revenue requirement includes depreciation in PECO's rate base. Second, forecasts of volumetric sales, customer charges, and demand charges are used with the revenue requirement to baseline customer rates without solar by performing a rate case every three years. Third, solar leads to avoided costs (i.e. a lower revenue requirement) and to reduced utility revenue from volumetric sales and demand charges that will affect PECO rates. Key parameters for the entire utility rate impact model are summarized in Table A1 of the appendix.

An important component of the rate impact model is estimating how solar avoids energy costs, generation capacity costs and transmission capacity costs. We estimate avoided energy costs embodied in the bilateral contracts that PECO signs with generators. These energy costs include losses, ancillary services, a risk premium, and the market cost of electricity on PJM's day ahead market. The avoided energy market costs are based on the coincidence of 10 years of solar output with corresponding Locational Marginal Prices. Using historical PJM supply curves, we also estimate market price suppression effects caused when solar reduces demand and the energy market clearing price. We estimate avoided generational capacity costs by replicating the weather normalized coincident peak forecast used to determine PECO's capacity obligation in PJM's capacity market, the Reliability Pricing Model (RPM). Finally, we estimate avoided transmission costs by identifying and simulating the deferral of growth-related projects in PJM's Transmission Cost Information Center. Method details and results are described in detail by Keen (2019).

When applied to a typical Northeastern utility, Satchwell et al. (2014) estimate that a 5% solar energy penetration will increase rates by 0.7%. We estimate a 0.9% increase in rates for the same 5% penetration assuming that solar is randomly placed throughout the PECO service territory (Keen, 2019). Our estimate for the value of solar is lower than the LBNL report's value because energy costs have declined and because we estimate a lower distribution deferral value of solar.

3.2 Capacity Deferral Model

3.2.1 Overview

The capacity deferral model estimates savings caused when solar and energy storage reduce peak demands and defer investments. In both the targeted placement and untargeted placement model, yearly capacity expenses are estimated and tracked when they are deferred to later years. The primary difference is that the amount of solar increases linearly in the untargeted scenario and peaks at a 5% energy penetration whereas the targeted scenario is limited only by feeder hosting capacity.

The length of time that the capacity investment is deferred depends on the reduction in load created by solar's effective capacity and the feeder load growth, as described by Equation 1.

$$Deferral\ Time = \frac{\ln\left(\frac{capacity\ of\ congested\ area}{capacity\ of\ congested\ area - effective\ solar\ capacity}\right)}{\ln(growth\ rate)} \quad (1)$$

Occasionally, enough solar can accumulate on feeders during a deferral period to allow another deferral after the initial deferral period expires. We allow a maximum deferral time of 20 years. Key parameters for the capacity deferral model are summarized in Table 1.

Table 1: Parameters for Capacity Deferral Model

Parameter	**Base case**	**Source**
Battery Unit Cost	0.5 Hours: \$2600/kWh 0.5-2 Hours: \$1400/kWh >2 Hours: \$400/kWh	(EIA, 2018)
Capex Cost Escalation	2%	(Bureau of Labor Statistics, 2018)
Deferrable Capex	1% of PECO Distribution Capex Budget (\$3 MM/year)	(PECO, 2018)
Deferral Time Min	1 Year	-
Deferral Time Max	20 Years	-
Feeder Load Profile for estimating D-ELCC	Based on four feeders with mostly residential customers and weather driven load modeling	(PECO, 2018) (Keen, 2019)
Feeder Solar Profile	Average of Peach Bottom, Doylestown, Philadelphia International Airport	(NREL, 2018)
Hosting Capacity	30% Peak Penetration	Appendix, Figure A1
Marginal Cost of Service	\$600/kW	(PECO, 2018)
Feeder Peak Demand Growth	1%	(PECO, 2018)
Solar Energy Penetration	5% Target, linear rollout from 2020-2030	-
Weighted average cost of capital, WACC (for discounting future capital expenses)	7.7%	Based on 10% Target ROE and 5% Debt with a 53/47% split.
Discount Rate (for estimating average rate change)	5%	-

3.2.2 Data

Data for the rate impact model came from a variety of sources including FERC Form 1 and rate case filings. Sources are provided in Table 1 and Table A1 (appendix).

We worked with PECO engineers to determine which capital investments in their 5-year spending plan could be deferred to later years. Four projects were identified (PECO 2018). This "growth-related capex" is about 1% of PECO's $300MM distribution capex budget. Based on a $600/kW MCOS, this is 5MW of installed capacity. Thus, in our model we assume one 5MW capacity project per year that can be deferred to later years.

We estimate the feeder load growth from the average growth rate of four PECO growth-related capacity projects over the last 5 years. We find that the growth in these areas is low, averaging 0.3%. This average excludes two large load increases of 100% and 50% that are likely one-time load changes from new customer connections.

An important parameter in the targeted placement scenario is the hosting capacity. In the appendix, we detail several modeling steps that we followed to estimate the hosting capacity on four PECO feeders. We find that the hosting capacity is limited by the voltage violations on secondary networks and typically around 30% peak penetration. This is lower than other estimates, such Hoke et al. (2013) that find peak penetration hosting capacities typically well above 50% if solar is placed uniformly through the distribution network. Our sensitivity analysis includes results with hosting capacities ranging from 0-100%.

3.3.3 Distribution Effective Load Carrying Capability

The modeled reduction in load depends on the capacity value assigned to solar. To be consistent with power systems standards, we call this capacity value the Distribution Effective Load Carrying Capability (D-ELCC), which we define as the net load reduction relative to solar system size. Our estimates of the D-ELCC are from Keen (2019) and are based on 19 years of solar and loading profiles from weather driven simulations. We define two D-ELCC metrics ($D\text{-}ELCC_{worst}$ and $D\text{-}ELCC_{age}$). In Figure 1, these metrics are shown as an average of two PECO feeders. A higher D-ELCC will increase the deferral time. When solar has a low D-ELCC, more solar must accumulate or be placed on a feeder to defer an investment by at least one year.

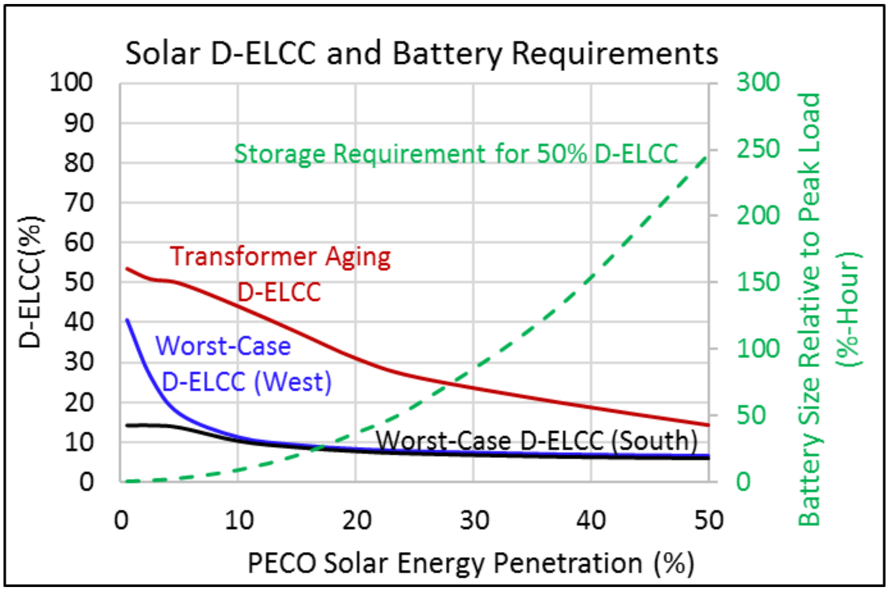


Figure 1: Distribution Effective Load Carrying Capability (D-ELCC). The worst-case D-ELCC does not allow any overloading over the 19 years. The worst-case D-ELCC is shown for South and West facing panels. The energy storage requirement to achieve a 50% worst-case D-ELCC over all penetrations is shown. The transformer aging D-ELCC allows occasional overloading but limits the total transformer aging (i.e. deterioration of insulation) to the aging incurred during typical weather normalization planning processes.

D-$ELCC_{worst}$ describes how much solar can reduce the largest net peak load over 19 years for each penetration. It does not allow any overloading. Most PECO feeders peak in the evening, so the D-$ELCC_{worst}$ is low. For capacity deferral projects where transformer overloading is the main constraint, relying on the inherent overloading flexibility of transformers rather than on costly energy storage can increase the D-ELCC. D-$ELCC_{age}$ allows occasional overloading but limits the total transformer deterioration (i.e. transformer "aging", estimated using IEEE Standard C57.91™) to the amount incurred during typical weather normalization planning processes. Because solar reduces transformer loading more often than it increases transformer loading, D-$ELCC_{age}$ is higher than D-$ELCC_{worst}$. A comprehensive assessment of the D-ELCC for several regions in the United States is in Keen (2019).

To complement D-$ELCC_{worst}$, Figure 1 shows the amount of energy storage required at varying solar energy penetrations to ensure a D-ELCC of 50%. The energy storage requirement is based on the maximum energy overload (MWH) over 19 years, assuming that solar has a D-ELCC of 50%. The energy storage duration is the ratio of the peak and energy overload. Based on a recent study by the EIA (2018), we assume that storage with a duration less than 0.5 hours costs \$2600/kWh, between 0.5 - 2 hours costs \$1400/kWh, and storage greater than 2 hours costs \$400/kWh. All estimates of the value of solar and total deferral value include these storage costs.

3.3.4 Targeted and Untargeted Solar Placement

The capacity deferral value associated with solar depends on how solar is deployed in congested areas. We consider the 'No Targeting' and 'Targeted Placement' scenarios in our analysis. In the 'No Targeting' scenario, solar is placed randomly throughout the service territory. The solar energy penetration on a deferrable project depends only on the target solar energy penetration over the solar rollout and the year of the rollout. In a given year, if the amount of solar in an overloaded location is very small there may not be enough solar to defer capex by at least a year, and the deferral opportunity will be missed. Because the solar accumulates over time, there may be enough solar to defer investments in later years.

In the 'Targeted Placement' scenario, solar is added to a capacity deferral project until the hosting capacity limit is reached. The total solar capacity installed on overloaded feeders cannot exceed the total incremental amount of solar capacity that becomes available each year. The relatively low number of capacity deferral projects means that there is enough solar to reach high hosting capacity limits. This is true even in most years beyond 2030 when solar is being added to maintain a constant penetration as load grows. Although we do not include 'Targeted Compensation' in our analysis, we do estimate the value of solar under targeted placement if only solar owners are compensated.

Figure 2 shows how yearly capacity investments change under these planning scenarios. Solar is not very effective at deferring capacity investments in the 'No targeting' scenario. There is not enough accumulated solar to defer a capacity project until the year 2025, and then, the deferral time is only one year. Capacity investments in the years following 2025 are also deferred by one year, so 2025 is the only year without any capacity investments.

Targeted placement and energy storage are more effective at deferring capacity investments. Without energy storage, targeted placement is able to defer investments by three years, including at the beginning of the solar rollout. There is enough solar added after 2030 that projects can continue to be deferred after 2030. Energy storage resulting in a 50% D-ELCC leads to 10-year deferral times. Capacity projects deferred beyond 2040 are discounted back to the year 2040 using PECO's 7.7% weighted average cost of capital (WACC).

The capacity investments in Figure 2 are used with a $600/kW MCOS and 2% escalation rate to generate a yearly cashflow. The cashflow is added to PECO's ratebase and depreciated with straight-line depreciation to determine yearly rates. Because deprecation will continue to take place beyond our study horizon (2016-2040), the net present value of solar and total deferral value-unlike rates-are instead calculated directly from the cashflow. The differing time horizons result in small inconsistencies between the rate impact and total deferral value for some scenarios.

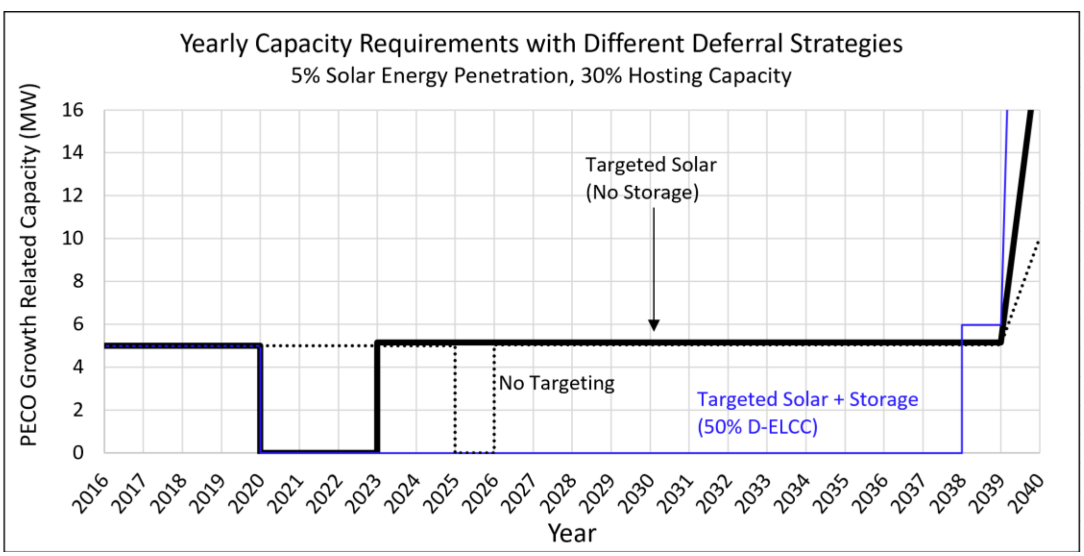


Figure 2: Capacity investments are deferred to later years when solar is added to PECO's service territory. Without any solar, PECO installs approximately 5MW of capacity that could be deferred every year. Without targeting, enough solar does not accumulate until the year 2025 to defer capacity projects and the deferral time is only 1 year. Targeted solar without storage and targeted solar with enough storage for a 50% D-ELCC, defer projects by 3 years and 18 years, respectively.

4. Results

The ability of solar to create deferral value and reduce rates is strongly influenced by network characteristics and whether solar is targeted at overloaded networks. Hosting capacities below 30% and peak load growths greater than 1% in overloaded networks both reduce the deferral value. A low D-ELCC can also eliminate deferral value and is common on PECO's evening peaking feeders, but options exist: energy storage can be used with solar, or if small amounts of overloading are allowed the D-ELCC increases rapidly. The largest source of uncertainty for capacity deferral value is the number of yearly projects that are deferrable.

Figure 3 shows the total deferral value for targeted and untargeted solar placement. Assuming the worst-case D-ELCC and a 30% hosting capacity, targeted placement increases the total deferral value approximately fourfold. The total deferral value increases for both targeted and untargeted scenarios when the transformer aging D-ELCC is used or when solar is combined with energy storage. Regardless of the energy storage or D-ELCC scenario, the total deferral value is much smaller if load growth is 2% on the capacity deferral projects (far right),

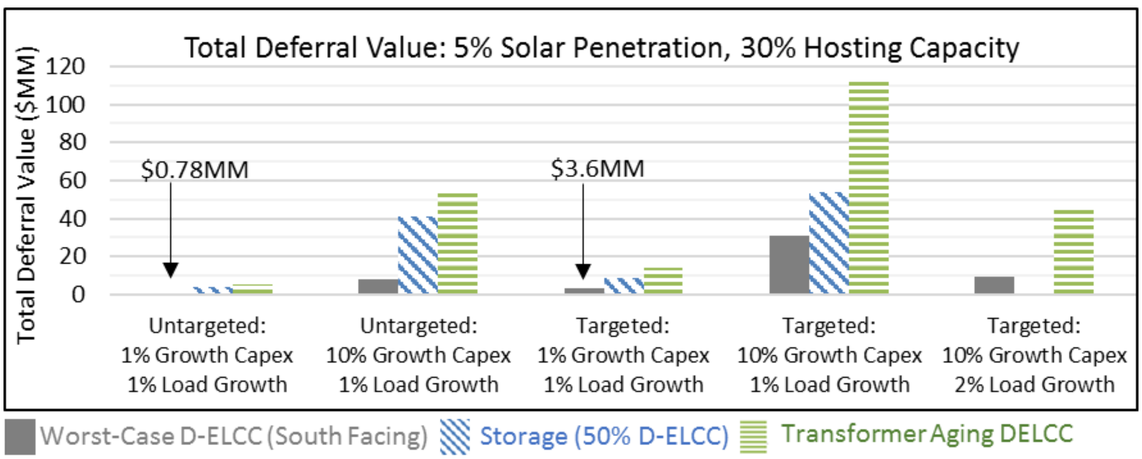


Figure 3: Total deferral value generated by untargeted and targeted solar placement. Assuming the Worst-Case D-ELCC, targeted placement increases the total deferral value approximately fourfold. The greatest deferral value is created with the transformer aging D-ELCC, followed by energy storage scenario which includes battery costs. A 2% load growth eliminates most savings because the deferral times are shorter.

Scenarios with a larger total deferral result in a larger rate decrease and a larger utility earnings decrease (Figure 4 and Figure 5). The rate impact and total deferral value are small if only 1% of PECO's distribution capex is growth-related. If 10% of PECO's distribution capex is growth-related and the transformer aging D-ELCC is applied to deferral projects, the rate increase from solar drops from 0.9% to 0.2%. However, a higher 2% growth rate would eliminate most deferral savings. As the total deferral value increases and rates decrease, utility earnings decrease. If the number of deferral opportunities is 1%, PECO is likely to be mostly indifferent to lost earnings from rooftop solar.

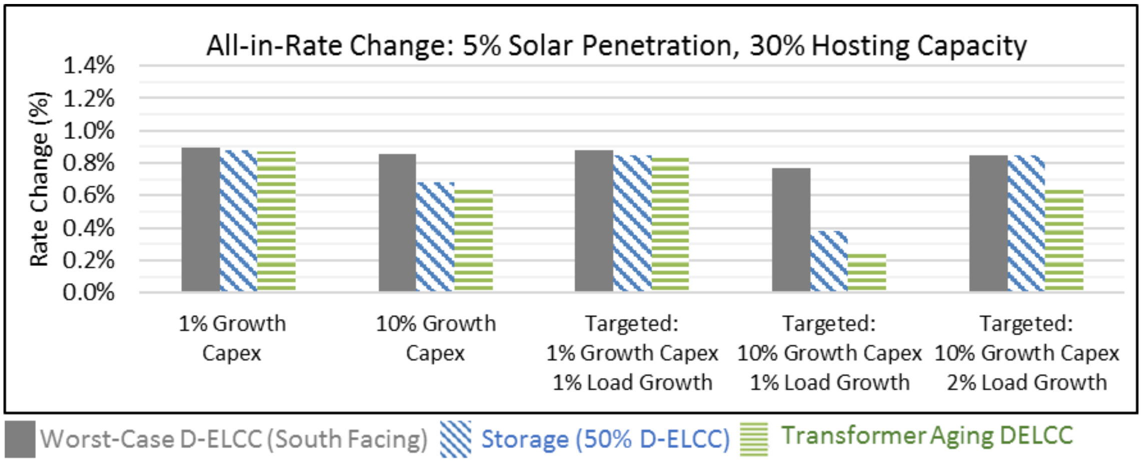


Figure 4: All-in-Rate Change with targeted and untargeted solar placement. Based on PECO's estimate that only 1% of their distribution capex is deferrable, both targeted and untargeted solar placement have a small effect on rates. If 10% of capex is deferrable, targeted placement is used, and storage or the transformer aging D-ELCC is applied, then there is a modest reduction in rates.

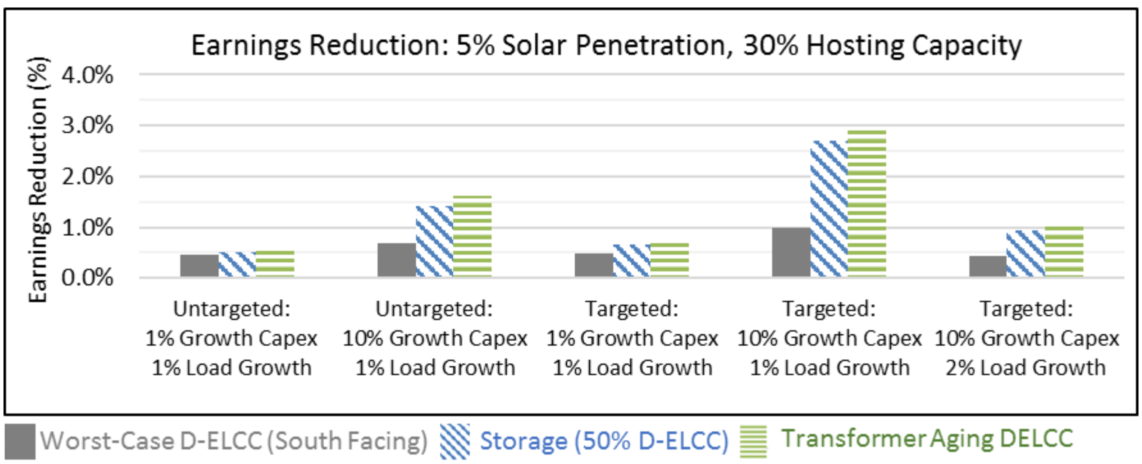
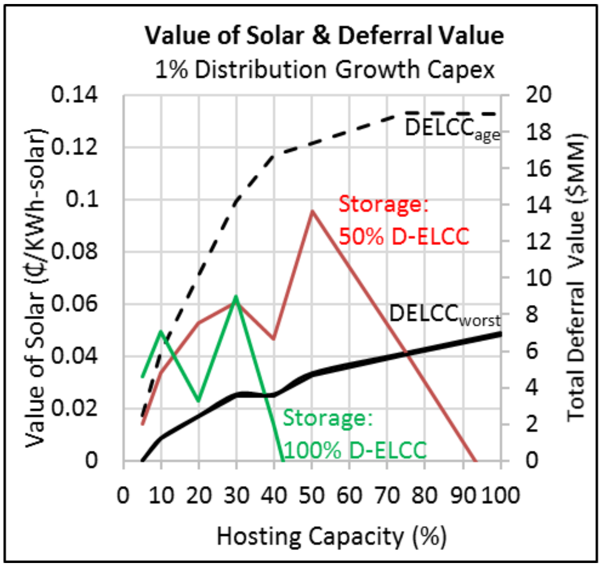


Figure 5: PECO earnings decrease as more capital investments are deferred.

While more challenging to monetize, longer deferral times resulting from targeted placement make capacity deferral more manageable within the utility planning process. Without any planning in the 'no targeting' scenario, typical deferral times are just one year. In contrast, assuming the worst-case D-ELCC, targeted placement with only solar typically results in deferral times of 3 years at 30% hosting capacity. The transformer aging D-ELCC can increase the typical deferral time to 13 years. Energy storage targeting a 50% and 100% D-ELCC can increase the deferral time to 18 and 20 years, respectively.

Figure 6 shows how the value of solar and total deferral value change for different hosting capacities. There is a rapid increase from 0-40% hosting capacity. The sawtooth pattern in the energy storage scenarios is caused because we model declining storage costs as a step function with increasing storage duration, based on EIA summary statistics (2018). The deferral value created by storage decreases rapidly with high hosting capacities because storage size requirements increase rapidly beyond a 10% energy penetration (Figure 1). We do not explicitly vary the MCOS in the sensitivity analysis in Figure 6 or Figure 7, but these results are directly proportional to the chosen MCOS. That is, a $300/kW would decrease the VOS in these figures by half.



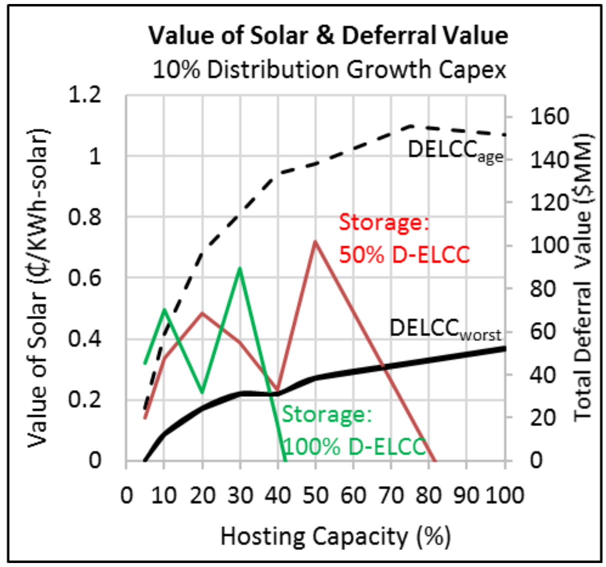


Figure 6: The value of solar and total deferral value increases rapidly from 0-40% hosting capacity. Energy storage does not generate additional value beyond 30-50% hosting capacity because of rising costs associated larger storage requirements.

The penetration of solar on most Pennsylvania feeders is very low. A challenge of targeted solar placement is finding enough customers interested in solar to meet the capacity deferral requirements. Utilities may be able to leverage their customer knowledge and work with third parties to achieve target solar penetrations. It is possible that financial incentives to encourage more solar installations will also be needed. Figure 7 shows the distribution deferral value of solar when only solar owners are compensated. The high VOS shows that there is enough value concentrated on individual feeders to encourage solar installations where they are needed. However, any incentives used to incentivize solar installations will reduce the ratepayer benefits of non-solar owners.

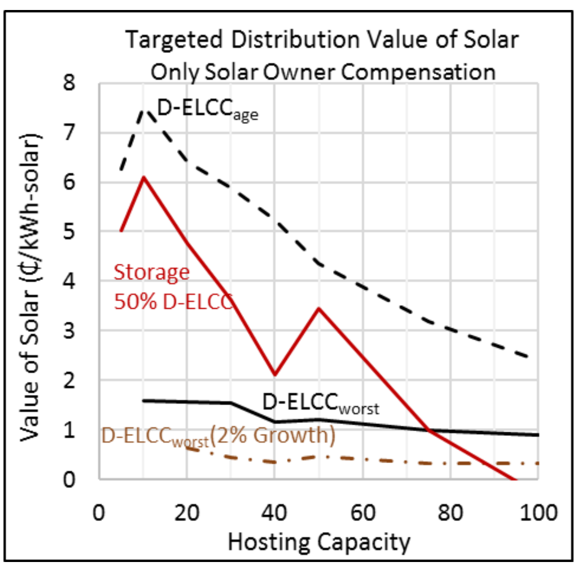


Figure 7: Targeted Distribution Deferral Value of Solar when allocated only to solar owners on overloaded networks. The value of solar is high enough to encourage new customers to install solar. 2% load growth causes a steep reduction in the value of solar (brown). All other scenarios assume 1% load growth.

5. Discussion and Future Research

We find that the capacity deferral value of solar at 5% energy penetration can be increased up to fourfold if solar is targeted at overloaded locations. Keen (2019) estimates that a 5% solar energy penetration of solar would increase rates in the PECO service territory by 0.9% over a 20-year horizon and generate just $1MM in net present deferral savings. A higher effective capacity (e.g. from coupling energy storage with solar) and targeted placement could generate $8MM of value over the same horizon but the rate increase is mostly unaffected (dropping to 0.8%). If 10% of PECO's capex is deferrable, the rate increase would drop to 0.5% and generate $70-100MM of deferral value over the same 20-year time horizon. We conclude that capacity deferral with solar should be included in PECO's planning process but that large administrative efforts to manage deferral projects, such as markets, are probably not warranted.

We were surprised at the low number of PECO capacity deferral opportunities. 90% of PECO's capex planned for the next five years is related to new customer connections, aging infrastructure and reliability (PECO, 2018). PECO engineers identified only $3MM per year of deferrable projects. In contrast, PECO plans to spend approximately $50MM per year on projects related to aging infrastructure and resiliency. This spending is partially related to Pennsylvania's Long-Term Infrastructure Investment Plan (LTIIP) that encourages utility investment in aging infrastructure by bypassing the rate case process and allowing quarterly rate increases to cover capital investments.

The high amount of LTIIP spending may be indirectly related to PECO's low growth-related spending. PECO, like many utilities, makes capacity investments assuming worst-case loading scenarios. Consequently, it is more likely for distribution equipment to reach its age limit before it becomes overloaded, and the capacity deferral paradigm may not be the best way to value solar and other Distributed Energy Resources (DER).

Future research could investigate the capacity value of solar beyond the traditional deferral paradigm. For example, utilities could take advantage of the optionality of DER by making smaller capacity investments and deploying DER as needed so that infrastructure reaches its age limit and loading limit at similar times. Where infrastructure is replaced due to technological obsolescence, solar may still have value if the replacement asset requires less capacity. Research is needed to determine whether this more complicated planning process would create savings. Utility engineers often justify making larger capital investments by citing the low marginal cost of equipment[2]. The low marginal cost of more capacity would need to be included in any assessment of using more DER.

Future research could also benefit from more granular data. We focused on capacity deferral on the primary network of distribution feeders. However, in their Marginal Cost study Consolidated Edison identified secondary network upgrades as a large portion of their system wide marginal cost (Hanser, et al. 2018). We also found a low number of capacity deferral opportunities but cannot generalize this observation to other utilities now or in the future where trends like electrification could increase load growth. Where more capacity deferral opportunities do exist, they have varying value. For example, Brattle (Hledik et al. , 2018) and E3 (Price, et al. 2013) observe a highly skewed distribution of capacity values in Nevada and California; there are small number of expensive projects and a large number of

[2] This marginal cost is different than the marginal cost of service (MCOS) cited previously. The MCOS is an average of new capacity additions whereas the marginal cost of equipment describes the incremental cost of equipment with added capacity.

projects with rapidly diminishing value. It would be useful to estimate the total deferral value under these circumstances.

6. Conclusion and Policy Recommendations

Deferral opportunities created by rooftop solar may serve as a modest opportunity for reducing rates, but several obstacles exist. In the PECO service territory, PECO engineers have identified few deferral opportunities. We recommend that the Pennsylvania PUC and utilities include an analysis of growth-related deferral opportunities in the standard least-cost planning process, and we offer the same recommendation to other states investigating the value of solar for their utilities.

In states with more deferrable growth-related projects, it is important to estimate the deferral value. States experiencing more deferrable opportunities may have higher load growth on their feeders, which can reduce the deferral time and the deferral value.

Using solar as a capacity resource for overloaded networks is often met with skepticism among utility managers, but we find this challenge can be managed with either energy storage or a D-ELCC metric that, like other probabilistic metrics used in power systems, allows occasional overloading. In the short term, due to its cost effectiveness and low risk, we recommend that utilities pilot capacity deferral projects with solar and storage. In the long term, utilities should consider deploying only solar to defer capacity investments unless the cost of storage decreases significantly.

Keen (2019), shows that the D-ELCC is high in regions with a strong solar resource. On evening peaking feeders, like in the PECO service territory or in regions with weaker solar, allowing occasional overloading on transformers can increase the effective capacity of solar and generate more deferral value. Transformers are designed to withstand loading beyond their nameplate capacity, and the effective capacity of solar can be set so that transforming aging does not increase with solar.

Finally, we recommend targeted placement of solar. Compared to untargeted placement, targeted placement can increase the total deferral value as much as fourfold. It also increases the total deferral time and will be more manageable within the utility planning process. In the PECO service territory, however, we did not observe enough total deferral value to warrant managing deferral opportunities with overly complicated market or administrative processes.

Acknowledgements

This work was funded by the Richard King Mellon Foundation and in part by the Carnegie Mellon Climate and Energy Decision Making Center (CEDM), formed through a cooperative agreement between the National Science Foundation and CMU (SES-0949710). The findings and conclusions in this material are those of the authors. We are grateful for the Pennsylvania Public Utility Commission, and PECO for providing data, technical expertise, and thoughtful comments. Special thanks to Eric Matheson and George Sey Jr.

References

Bureau of Labor Statistics. 2018. *New Producer Price Indexes for Electric Power Generation, NAICS 221110, and Electric Bulk Power Transmission and Control, NAICS 221121.* https://www.bls.gov/ppi/ppipower.htm.

Cohen, M. A., P. A. Kauzmann, and D. S. Callaway. 2016. "Effects of distributed PV generation on California's distribution system, part 2: Economic Analysis." *Solar Energy* 128: 139-152. http://dx.doi.org/10.1016/j.solener.2016.01.004.

CPUC. 2016. *DRP Workshops.* December 12. http://www.cpuc.ca.gov/drp_workshops/.

E3. 2018. *Cost-effectiveness-Avoided Cost Calculator.* http://www.cpuc.ca.gov/General.aspx?id=5267.

EIA. 2018. "U.S. Battery Storage Market Trends." May. https://www.eia.gov/analysis/studies/electricity/batterystorage/pdf/battery_storage.pdf.

EPRI. 2015. *The Integrated Grid: A Benefit-Cost Framework.* Palo Alto: EPRI. https://www.epri.com/#/pages/product/3002004878/?lang=en-US.

Hanser, Philip Q, T. Bruce Tsuchida, Pearl Donohoo-Vallett, Lynn Zhang, and Jens Schoene. 2018. *Marginal Cost of Service Study.* The Brattle Group. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF99CFC43-2D67-44DB-AB02-A7ACDA5E6341%7D.

Hledik, Ryan, Judy Chang, Roger Lueken, Johannes Pfeifenberger, John Imon Pedtke, and Jeremy Vollen. 2018. *The Economic Potential for Energy Storage in Nevada.* The Brattle Group. https://brattlefiles.blob.core.windows.net/files/14618_economic_potential_for_storage_in_nevada_-_final.pdf.

Hoke, Anderson, Rebecca Butler, Joshua Hambrick, and Benjamin Kroposki. 2013. "Steady-State Analysis of Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders." *IEEE Transactions on Sustainable Energy* 350-357. doi:10.1109/TSTE.2012.2225115.

Horii, Brian, Snuller Price, Eric Cutter, Zachary Ming, and Kiran Chawla. 2016. *Avoided Costs 2016 Interim Update.* E3. http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=12504.

Keen, Jeremy. 2019. "Stakeholder Costs and Benefits of Distributed Energy Resources on Distribution Networks." Ph.D. dissertation, Carnegie Mellon University, Pittsburgh. https://doi.org/10.1184/R1/7808372.v1.

Mills, Andrew, and Ryan Wiser. 2012. *Changes in the Economic Value of Variable Generation at High Penetration Levels: A Pilot Case Study of California.* Berkeley: Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/all/files/lbnl-5445e.pdf.

NAPEE. 2007. "Aligning Utility Incentives." https://www.epa.gov/sites/production/files/2015-08/documents/incentives.pdf.

New York DPS. 2015. "Report of the Market Design and Platflorm Technology Working Group." Albany. http://www3.dps.ny.gov/W/PSCWeb.nsf/All/5E74ED080A95647085257E7000425E60?OpenDocument.

NREL. 2018. *NSRDB Data Viewer.* https://maps.nrel.gov/nsrdb-viewer/.

NYSERDA. 2015. *The Benefits and Costs of Net Energy Metering in New York.* Energy and Environmental Economics. http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7BF4166D6E-CBFC-48A2-ADA1-D4858F519008%7D.

O'Connell, A., J. Roark, B. Rogers, and J. Smith. 2017. *Time and Locational Value of Photovoltaics (PV) on Distribution Feeders in Spain.* Palo Alto: Electric Power Research Institute. https://www.epri.com/#/pages/product/000000003002011694/?lang=en-US&lang=en-US.

PECO. 2018. "Private Communications." Philadelphia.

Price, Snuller, Brian Horii, Michael King, Andrew DeBenedictis, Jenya Kahn-Lang, Katie Pickrell, Ben Haley, et al. 2013. *California Net Energy Metering Ratepayer Impacts Evaluation.* San Francisco: E3. http://www.cpuc.ca.gov/General.aspx?id=8919.

Satchwell, Andrew, Andrew Mills, Galen Barbose, Ryan Wiser, Peter Cappers, and Naim Darghouth. 2014. *Financial Impacts of Net-Metered PV on Utilities and Ratepayers: A scoping Study of Two Prototypical U.S. Utilities.* Lawrence Berkeley National Laboratory. https://emp.lbl.gov/sites/all/files/LBNL%20PV%20Business%20Models%20Report_no%20report%20number%20(Sept%2025%20revision).pdf.

Trabish, Herman. 2017. *More than 30 states embrace grid modernization, new policy tracker finds.* May 31. https://www.utilitydive.com/news/more-than-30-states-embrace-grid-modernization-new-policy-tracker-finds/443702/.

Willis, H. Lee. 2000. *Distributed Power Generation: Planning and Evaluation.* New York: Marcel Dekker, Inc. .

Woo, C. K., Rwn Orans, Brian Horii, Roger Pupp, and Grayson Heffner. 1994. "Area - and Time-Specific Marginal Capacity Costs of Electricity Distribution." *Energy* 1213-1218. https://www.sciencedirect.com/science/article/pii/036054429490023X.

Appendix

Table A1 shows parameters in the utility rate impact model. Figure A1 shows how increasing solar penetrations increase the number of new voltage violations on four PECO feeders. This required several steps.

First, PECO selected four feeders that are representative of their service territory. Second, we converted PECO's feeder models from CYMDIST, which performs only static powerflow analysis, to GridLab-D, which can also do sequential time-series powerflow analysis. Third, we populated the GridLab-D feeder models with representative secondary networks and weather dependent building models, ensuring that the total simulated substation load was similar to SCADA readings and that the maximum simulated spot loads were similar to the spot load values in PECO's models. Fourth, we populated the GridLab-D feeder models with residential and commercial solar PV by drawing from a probability distribution of the nominal capacity (kW_{AC}) of recent solar installations. Fifth, we simulated varying penetrations of solar on the models with different voltage excursion mitigation scenarios. In our reconductoring scenario, if a solar installation caused a voltage excursion, the capacity of the service drop conductor connecting the solar installations was increased by 100 amps. In our smart inverter scenario, we connected smart inverters to all solar installations. Further details are in Keen (2019).

Depending on the feeder, the number of voltage violations begins to increase rapidly when energy penetrations reach 10%. We did not find distribution system reconductoring to be very effective at reducing voltage violations. Volt/Var smart inverters with reactive power priority was the most effective and we found the costs of real power curtailment associated with this inverter to be negligible (less than a 0.01 ₵/kWh). Beyond penetrations of 5-10%, more expensive interconnection costs may be incurred.

Table A1: Base case assumptions for utility rate impact model. Solar is installed randomly throughout the service territory and solar owners are compensated at the retail rate (i.e. with Net Energy Metering).

Input	PECO Input	Source
Study Period	2016-2040. Solar deployed 2020-2030	-
Solar PV Compensation	Net Energy Metering (NEM)	-
Peak Load, Growth	8,364 MW, 0.7%	(PJM, 2016)
Load Factor	48.6%	(PA PUC, 2017)
Forecast Sales Growth	0.6%	(PJM, 2016)
Customer Count, Growth	1.6 Million, 0.52%	(PA PUC, 2017)
Average, Peak Losses	6.4%, 8%	(PA PUC, 2017)
Rate Base Assets	$4,100 Million	(PA PUC, 2015)
Avg. Asset Book Depreciation	30 years	(FERC, 2016)
Capex, Escalation	$398 Million at 2% escalation	(FERC, 2016) (Bureau of Labor Statistics, 2018)
LTIIP Capex	$55 Million	(FERC, 2016)
O&M, Escalation	$829MM at estimated 0.5% escalation	(FERC, 2016)
Rate Case Trigger	Every three years	(PA PUC, 2018)
Test year	"Fully Projected Future Test Year" (2 years)	(PA PUC, 2012)
Regulatory Lag	1 year	(PA PUC, 2018)
Target Return on Equity	10%	(PA PUC, 2015)
Debt Cost, percentage	5.04%, 46.64%	(PA PUC, 2015)
Federal Tax Rate	20%	(IRS, 2018)
State Tax Rate	9.99%	(PA Dept. of Revenue, 2019)
Average Bilateral Contract	$45/MWh in 2020 (includes load-weighted LMP, capacity market, ancillary services, AEPS costs, and the risk premium)	(PECO, 2019)
Energy Escalation Rate	Indexed to EIA reference forecasts for coal and natural gas	(EIA, 2018)
Generation Capacity, Escalation	Average 164/MW-day and estimated 0% escalation based on recent years	(PJM, 2018)
Reserve Margin	Estimated 20.5% planning margin.	(PJM, 2018)
PJM Transmission Escalation	4.3%	(Bureau of Labor Statistics, 2018)
PJM Transmission Growth Capex	Estimated from PJM Transmission Cost Information Center. $46MM/year	(PJM, 2019)
PECO Transmission Growth Capex	Estimated from PJM Transmission Cost Information Center. $6MM/year	(PJM, 2019)
REC Price	Estimated from PA AEPS Reporting. $8/MWH	(PA PUC, 2016)
Growth Related Capex	1% of distribution capex or $3MM per year	(PECO, 2018)
Distribution Marginal Cost of Service	Estimated $600/kW from four recent projects	(PECO, 2018)
D-ELCC	Based on worst case loading over 19 years and two PECO feeders.	(Keen, 2019)

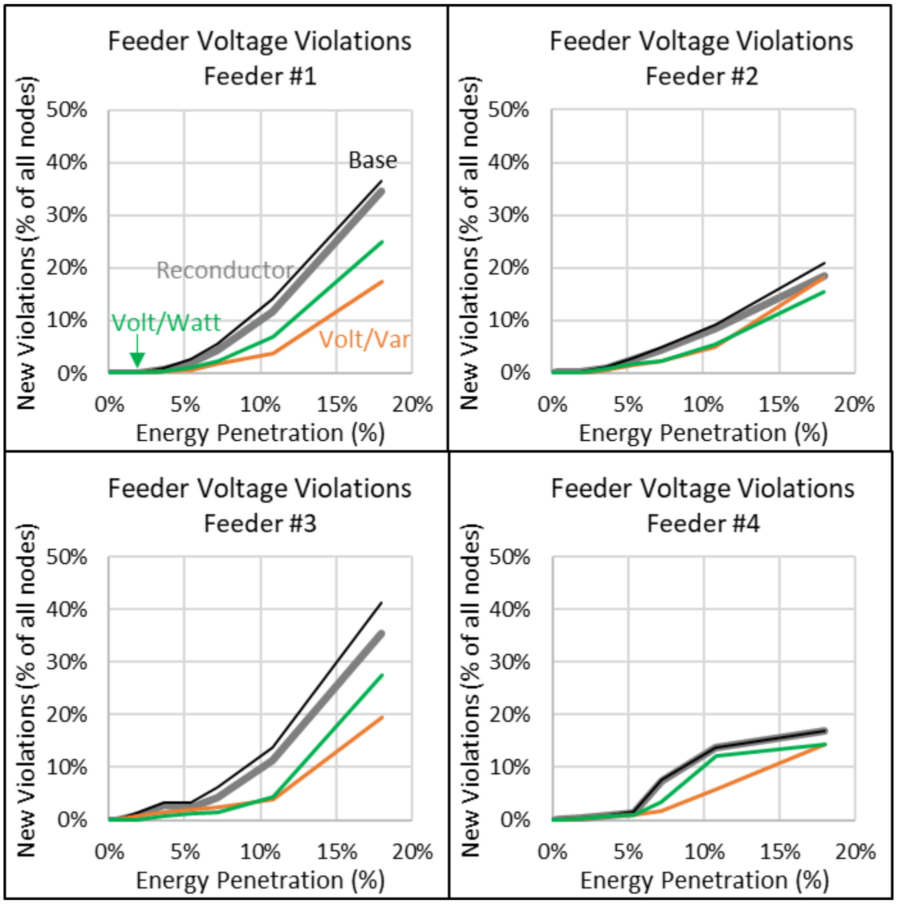


Figure A1: The number of voltage violations are small below 5% energy penetration but begin to increase quickly for penetrations ranging from 5-10%. Volt/Var is a smart inverter with reactive power priority. We found Volt/Var smart inverters to be most effective and the least-cost method for mitigating voltage violations.

References

Bureau of Labor Statistics. 2018. *New Producer Price Indexes for Electric Power Generation, NAICS 221110, and Electric Bulk Power Transmission and Control, NAICS 221121.* https://www.bls.gov/ppi/ppipower.htm.

EIA. 2018. *Annual Energy Outlook 2018.* Washington, DC: EIA. https://www.eia.gov/outlooks/aeo/.

FERC. 2016. "PECO: FERC Financial Report (FERC Form No.1): Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 30Q: Quarterly Financial Report." Q4.

IRS. 2018. "Instructions for Form 1120." https://www.irs.gov/pub/irs-pdf/i1120.pdf.

Keen, Jeremy. 2019. "Stakeholder Costs and Benefits of Distributed Energy Resources on Distribution Networks." Ph.D. dissertation, Carnegie Mellon University, Pittsburgh. https://doi.org/10.1184/R1/7808372.v1.

PA Dept. of Revenue. 2019. *Partnerships/S Corporations/Limited Liability Companies.* March.

https://www.revenue.pa.gov/GeneralTaxInformation/Tax%20Types%20and%20Information/Partnerships-S-Corps-LLCs/Pages/default.aspx.

PA PUC. 2016. *2016 Annual Report: Alternative Energy Portfolio Standards Act of 2004.* Harrisburg: PA Public Utility Commission, PA Department of Environmental Protection. http://www.puc.state.pa.us/Electric/pdf/AEPS/AEPS_Ann_Rpt_2016.pdf.

PA PUC. 2017. "Electric Power Outlook for Pennsylvania: 2016-2021." Harrisburg. http://www.puc.state.pa.us/General/publications_reports/pdf/EPO_2017.pdf.

—. 2015. "PECO Energy 2015 Electric Rate Case (Docket No. R-2015-2468981)." http://www.puc.state.pa.us//pcdocs/1350400.pdf.

—. 2018. "Private Communications." Harrisburg.

PECO. 2019. *PECO Procurement for Default Supply.* January. http://www.pecoprocurement.com/index.cfm?s=background&p=previousResults.

—. 2018. "Private Communications." Philadelphia.

PJM. 2018. *Capacity Market (RPM).* September. https://pjm.com/markets-and-operations/rpm.aspx.

—. 2019. *Cost Allocation.* https://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx.